TECHNICAL REVIEW DOCUMENT OPERATING PERMIT 960PMR171

to be issued to:

Colorado Power Partners Morgan County Source ID 0870027

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Revised by Jacqueline Joyce
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I. Purpose:

This document establishes the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, the Public and other interested parties. Conclusions made in this report are based on information provided by the applicant in the Title V application submitted February 23, 1996, additional technical information submitted February 4 and May 11, 1999, March 31, July 10 and October 5, 2000, comments on the draft permit and technical review document received on December 19, 2001, comments on the draft permit received during the Public Comment period, a site visit, various telephone conversations and e-mail correspondence with the source and review of Division files. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised Construction Permit.

The word "credible" as it is used in the term "credible evidence" shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence.

II. Source Description:

This source is primarily classified as a cogeneration facility defined under Standard Industrial Classification 4911. Electricity for sale is produced by two combustion turbines, each equipped with a diesel-fired starter combustion engine and one duct burner. The turbines are equipped with enhanced water/steam injection systems to control NO_X emissions. One turbine (Brush 3) runs in simple cycle mode (turbine only) and the other turbine (Brush 1) can run in either simple cycle mode or combined cycle mode (turbine plus duct burner). Brush 1 and 3 are both equipped with a 25 MW (nominal) electric generator to provide power (in simple cycle mode) and the waste heat from Brush 1 is used to generate steam to drive a steam turbine (30 MW) for additional electricity (combined cycle mode). The waste heat from the steam turbine is used to heat a greenhouse complex. There are also three natural gas fired boilers to provide emergency heat to the greenhouses in the event that the turbines don't produce enough heat and a cooling tower to cool water for the steam turbine. Note that the combustion turbines are referred to as Brush 1 or GT1 (combined cycle) and Brush 3 or GT2 (simple cycle).

The facility is located on 90 acres just south of Brush in an area designated as attainment for all criteria pollutants. The facility includes a fossil fuel-fired steam electric plant of more than 250 million Btu per hour input which is one of the 28 listed sources with a major stationary source threshold of 100 tons per year of any criteria pollutant. Therefore, this source is considered to be a major stationary source in an attainment area (Potential to Emit > 100 tons/year) and has a PSD permit. Future modifications to this facility which are in excess of significance levels as defined in Colorado Regulation No. 3, Part A, Section I.B.58, would result in a major modification and the application of PSD requirements. The Colorado Power Partners (CPP) turbines are considered to be a single stationary source with the Brush Cogeneration Partnership (BCP) turbine (Brush 2) and the Colorado Energy Management (CEM) turbines (Brush 4) and separate operating permits will be issued to BCP and CEM. Facility wide emissions (includes CPP, CEM and BCP) and CPP only emissions are as follows:

Pollutant	Facility Potential to Emit ¹	CPP Potential to Emit ² (tons/yr)
	(tons/yr)	(303.07)
PM	60.89	8.19
PM ₁₀	60.89	8.19
NO _X	341.7	141
SO ₂	4.4	-
CO	386.1	149.3
VOC	70.4	24.5

¹Potential to emit for the facility is based on emissions from the CPP turbines, the Brush

Cogeneration Partnership turbine and the two Colorado Energy Management turbines. ²The current construction permit for CPP does not provide SO₂ emission limits.

Potential to Emit is based on permitted emission limits. The Division's emission inventory indicates that CPP typically reports and pays fees on potential emissions, which is an acceptable practice, and therefore no actual emission data is available.

There are no Federal Class I designated areas within 100 kilometers and no affected states within 50 miles of this facility.

This facility certified within the Title V permit application they are not subject to 112(r), the Accidental Release Requirements.

CPP submitted an application to modify their construction permit in April 1995, as CPP was unable to meet the NO_X and CO BACT limits identified in their construction permit. A compliance order on consent (COC) was issued December 18, 1995, which included stipulations that CPP upgrade one of the turbines to meet specific emission limitations identified in the COC, restricted the turbines to non-simultaneous operation and required CPP to install and operate continuous emission monitors and a continuous monitoring system to measure and record the flowrate of water used for injection to control NO_x emissions. In their Title V permit application, submitted Feburary 23, 1996, CPP certified to non-compliance with the NO_X, CO, VOC, and Particulate Matter emission limitations and fuel usage limits contained in the Construction Permits (in effect at the time) for the boilers (Units S003-S005) and the lb/hr CO, ppm CO and ppm NO_X emission limitations for the turbines (Units S001-S002), as revised construction permits had not been issued yet. Subsequent revised construction permits were issued on March 5, 1996 (included revised BACT limits for NO_X and CO) and March 27, 1997 (increased natural gas consumption and emission limitations). With the issuance of these revised construction permits, the CPP turbines are now in compliance with the NO_x, CO, VOC and Particulate Matter emission limitations.

In February 1999, CPP submitted an application to modify their construction permit to allow simultaneous operation of the turbines. The COC issued in December 1995, required CPP to identify a primary and standby turbine and to install a retrofit package on the primary turbine to meet specified NO_X and CO emission limits. The COC also indicated that the standby turbine could only be used when the primary turbine was out of service and such operation could not exceed 250 hours per year, unless a retrofit upgrade package at least equal to the primary turbine is installed. CPP had installed a retrofit upgrade package and indicated in their February 1999 construction permit application that the standby turbine could meet the emission limitations identified in the existing construction permit. A revised construction permit was issued on October 26, 1999 to allow simultaneous operation of the turbines. Note that with the revised construction permit, the NO_X BACT limits were reduced from the levels in the previous version

of the permit, with a further reduction in the NO_X BACT limits required after 24 months of operation. The issuance of the construction permit effectively modified the conditions in the December 1995 COC.

Note that construction permit 91MR933 incorrectly refers to Brush 3 as GT-3.

III. Emission Sources:

The following sources are specifically regulated under terms and conditions of the Operating Permit for this Site:

<u>Units S001/S002</u> - Two (2) Westinghouse 251AA Natural Gas Combustion Turbines, Rated at 420 mmBtu/hr each, SN's: 17A-2144 (GT-3) and 17A-2142 (GT-1), Equipped with One (1) Duct Burner, Rated at 180 mmBtu/hr. Two (2) Cummins BT171OP-635 Diesel Fired Reciprocating Starter Engines, SN's: Unknown.

Discussion:

- 1. Applicable Requirements- The units above were installed and began operating in 1990 and 1991, respectively. These units were issued initial approval construction permits 91MR933-(1-2) in April 1992. The permits were modified in June 1992 to incorporate the starter diesel engines, again in March 1996 to combine permits 91MR933-(1-3) and modify one turbine to come into compliance with Best Achievable Control Technology (BACT). A final approval construction permit 91MR933 was issued on March 27, 1997 with increased natural gas consumption limits and emission limits. In February 1999, the source requested to retrofit the stand-by unit and allow simultaneous operation of the turbines (one in combined cycle (Brush 1) and one in simple (Brush 3)) during peaking times. The Initial Approval modification was issued on October 26, 1999 with the following applicable requirements:
 - This source is subject to the odor requirements of Regulation No. 2 (condition 3)
 - Turbines are not generally a source of odor therefore this condition will not be specifically included in the permit but is included in the General Conditions (Section V) of the permit.
 - Compliance with the emission limits specified with effect from May 25, 2001 shall be demonstrated by that date (condition 4).

Note that this requirement will not be included in the permit, since, with the issuance of the operating permit, the source is required to submit semi-annual deviation reports and to certify compliance annually.

 Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 5 and Colorado Regulation No. 1, Sections II.a.1 & 4).

Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term "normal operations" applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered "normal operation". Therefore, the language in the permit will not specify "normal operation". Note that it will also be specified in the permit that the 20% opacity requirement applies during shutdown and offline emissions. In addition, in the permit the 30% opacity requirement will be written to include all the specific operational activities identified in Reg 1.

- This source shall be limited to a maximum consumption rate as listed below and all other activities, operation rates and numbers of equipment as stated in the application. Monthly records of the actual throughput shall be maintained by the permittee and made available to the Division for inspection upon request (condition 6).
 - o Consumption of natural gas for combustion in the turbines and duct burners, together, shall not exceed 2.240 mmSCF/vr.

Note that this condition also addresses fuel consumption limits for the boilers, which will be discussed in the boiler section later in this document, but does not put any fuel consumption limits on the starter engines. Previous versions of the construction permit (specifically the March 27, 1997 final approval permit) included a limitation on diesel fuel consumption of 4,000 gal/yr and it appears that this limit was inadvertently not included in the most recent version of the construction permit. The 4,000 gal/yr limit on diesel fuel consumption will be included in the operating permit.

 This source is subject to the requirements of Prevention of Significant Deterioration (PSD). Best Available Control Technology (BACT) shall be applied for control of Oxides of Nitrogen (NO_X) and Carbon Monoxide (CO) (condition 7).

NO_X:

- o Further modification to the combustion system, coupled with water injection is BACT for turbines.
- o Low NO_X combustion system is BACT for duct burners and boilers.

CO:

- Good combustion control, coupled with optimized water injection is BACT for turbines.
- Emissions of air pollutants from the turbines and duct burner together shall not exceed the following limitations (condition 8):

Effective until May 24, 2001:*

Particulate Matter 5.0 tons/yr PM₁₀ 5.0 tons/yr Nitrogen Oxides 158.0 tons/yr

Simple-cycle 30 ppmvd @ 15% oxygen, hourly average Combined-cycle 38 ppmvd @ 15% oxygen, hourly average

Volatile Organic Compounds 24.2 tons/yr Carbon Monoxide 147.5 tons/yr

50 ppmvd @ 15% oxygen, hourly average

Effective on and after May 25, 2001:

Particulate Matter 5.0 tons/yr PM₁₀ 5.0 tons/yr Nitrogen Oxides 134.0 tons/yr

Simple-cycle 25 ppmvd @ 15% oxygen, hourly average Combined-cycle 33 ppmvd @ 15% oxygen, hourly average

Volatile Organic Compounds 24.2 tons/yr Carbon Monoxide 147.5 tons/yr

60 ppmvd @ 15% oxygen, hourly average

*Note that the emission limitations for the period up to and including May 24, 2001 have not been included in the permit, since they no longer apply.

The previous version of this permit (modification 3, issued March 27,1997) included SO_2 emission limits of 3.4 tons/yr but the current version does not. Since the current permit provides the same fuel consumption limits as the March 27, 1997 permit it is not clear why the SO_2 emission limits were not included. It is presumed that this was an oversight and the 3.4 tons/yr limit from the March 27, 1997 construction permit have been included in the operating permit.

The source has indicated that they cannot meet the BACT limits provided in the permit during periods of startup, shutdown and partial load. EPA guidance (John B. Rasnic to Linda M. Murphy, dated January 28, 1993, "Automatic or Blanket Exemptions for Excess Emissions during Startup and Shutdowns Under PSD") states that "... PSD permits cannot contain automatic exemptions which allow excess emissions during startup and shutdown....the exemptions granted under some New Source Performance Standards (NSPS) are not applicable to this issue under

PSD. The NSPS are technology based standards that are not directly required for meeting ambient standards." Furthermore EPA guidance (Kathleen M. Bennett to Regional Administrators, dated February 15, 1983, "Policy on Excess Emissions During Startups, Shutdowns, Maintenance and Malfunction") indicate that "...startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation of the operating procedure for the process and control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods."

The January 28, 1993 EPA memo addresses using alternate limitations during startup and shutdown. Although they do not necessarily approve this method, they point out that these types of standards need to have clear definitions and limits and that the standard should demonstrate compliance with the short term PSD increments and ambient air standards, as well as the long term ambient air standards. The Division has opted to take the approach to provide an alternate BACT limit during periods of startup and shutdown, when the source indicates that they cannot meet the BACT limits in their permits during these periods. In order to provide an alternate BACT limit during startup and shutdown, the source must demonstrate that with this alternate BACT limit, compliance with the short and long-term NAAQS and PSD increments can be maintained. The source submitted modeling on July 10, 2000 demonstrating that with their requested alternate BACT limits for startup and shutdown that there are no significant impacts to the NAAQS or PSD increments. The source requested the following alternate BACT limits in their March 31, 2000 submittal:

Startup	NO_X	60 ppmvd @ 15% O ₂	CO 360 ppmvd @ 15% O ₂
Shutdown	NO_X	60 ppmvd @ 15% O ₂	CO 350 ppmvd @ 15% O ₂

At the request of the Division, CPP submitted continuous emission monitoring data from several startups and shutdowns on October 5, 2000. The Division reviewed the data and calculated average emissions for the event, for a partial hour (typically only includes either startup or shutdown data) and for a full hour (most likely includes some "normal" data). A review of this data indicates that the source's requested alternate BACT limits are at much higher levels than the data indicates the turbines operate at (see the Division's attached analysis of the startup and shutdown data). Therefore, the Division will include the following limits as alternate BACT limits in the permit for startup and shutdown:

Startup	NO_X	40 ppmvd @ 15% O ₂	CO 200 ppmvd @ 15% O ₂
Shutdown	NO_X	60 ppmvd @ 15% O ₂	CO 200 ppmvd @ 15% O ₂

The Division is aware that the data CPP submitted is from only a few startups and shutdowns. However, we believe that based on the data CPP provided they can comply with these limits. However, if at some time in the future, CPP demonstrates that they cannot consistently meet these startup and shutdown limits, the Division will review the data, reconsider the alternate startup and shutdown BACT limits and modify the permit if necessary and appropriate.

Note that startup and shutdown are defined as follows:

<u>Startup</u>: begins when fuel is injected into the gas turbine and ends when gross power output from the gas turbine first reaches or exceeds 10 MW. <u>Shutdown</u>: begins when the order to shutdown is sent and gross power output from the gas turbine is equal to 10 MW or less and ends when emissions cease.

- The turbines are subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part A Federal Register Regulations Adopted by Reference, Subpart GG Standards of Performance for Stationary Gas Turbines (condition 9):
 - o $NO_X \le 75$ ppmvd at 15% oxygen. (By meeting BACT this standard is satisfied)
 - o $SO_2 \le 150$ ppmvd at 15% oxygen.

These requirements were specifically included in the construction permit, however certain requirements were not included in the construction permit that do apply to these turbines. The following requirements also apply and will be included in the permit:

- o Exemptions from the NO_X limits, under certain special conditions, provided in 40 CFR Part 60 §§ 60.332(f) & (i).
- No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight (§ 60.333(b))
- The owner or operator shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within ± 5 percent (§ 60.334(a)).
- o The owner or operator shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine on a daily basis. A custom schedule may be developed for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. Custom schedules must be approved before they may be used (§ 60.334(b)(2))
- o Excess emissions reporting requirements (§ 60.334(c))
- o Performance test requirements, regarding fuel sampling (§§ 60.335(d) & (e))

- The duct burner is subject to Regulation No. 6, Part A, Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (condition 9):
 - o $NO_X < 0.2$ pounds per mmBtu.

This was the only requirement included in the construction permit, however certain requirements were not included in the construction permit that do apply to the duct burner. The following requirements also apply and will be included in the permit:

- o The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor for each calendar quarter. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month (§ 60.49b(d).
- o All records required under this section shall be maintained for a period of 2 years (§ 60.49b(o)).
- The turbines and the duct burner are subject to the requirements in 40 CFR Part 60 Subpart A New Source Performance Standards General Provisions, as adopted by reference in Colorado Regulation No. 6, Part A, the following will be included in the permit (condition 9):
 - o Good practices (§ 60.11(d))
 - o Circumvention (§ 60.12)

Note that a more extensive list of requirements from 40 CFR Part 60 Subpart A was included in the construction permit. However, these requirements, if still applicable, will be included in the permit as periodic monitoring or under the continuous emission monitoring requirements and will not be specifically identified as requirements under the NSPS general provisions.

In addition, the permit included the requirement for excess emission reports (40 CFR Part 60 Subpart A § 60.7(c)). The NSPS specifies that these reports shall be submitted semi-annually, except when more frequent reporting is required by the applicable subpart or if the Division determines that more frequent reporting is necessary to accurately assess the compliance status of the emission unit. The Division has determined that more frequent reporting is necessary and therefore, excess emission reports shall be submitted quarterly.

- The exhaust stacks of the turbines and duct burner shall be equipped with a continuous emission monitoring (CEM) system to measure and record the following (condition 10):
 - o Concentration of Oxides of Nitrogen, weighted hourly average

- o Emission rate of Oxides of Nitrogen, pounds/hour, tons per 12-month period.
- o Concentration of Carbon Monoxide, weighted hourly average
- Emission rate of Carbon Monoxide, pounds/hour, tons per 12month period.

Although not identified in the construction permit, the continuous emission monitor shall be required to monitor and record the gross output, in MW, of each turbine. Since the definition of startup and shutdown are based on the turbine output, it is necessary for the monitoring system to record the gross output of the turbine.

 Quality assured CEM data shall be available for a minimum of 90% of the duration of the operation. For the periods when such data is not available, the highest reading recorded during the previous 30-day period shall be used for determining the emissions (condition 10).

The construction permit specifies that the continuous monitoring system requirements in 40 CFR Part 60 Subpart A § 60.13 apply (condition 9.m). The requirement to provide quality assured data for 90% of the duration of the operation conflicts with the requirements in § 60.13(e), which requires that the continuous monitoring system be operated at all times, except under certain conditions. Therefore, it was not appropriate for the Division to include the 90% requirement in the construction permit. This requirement will not be included in the operating permit.

In addition, the Division considers that the data replacement requirements in 40 CFR Part 75 are more appropriate to use to replace data, rather than the language in the construction permit (highest reading recorded during the previous 30-day period) and the source has agreed to this. Therefore, the construction permit data replacement requirements will be modified directly in the operating permit to specify that data will be replaced in accordance with the procedures in 40 CFR Part 75.

- The Division may take direct enforcement action based solely on CEM data if the data shows any excursions above the NO_X and CO limitations established above (condition 10).
- Continuous emission monitoring systems shall be installed, maintained, calibrated, and operated according to 40 CFR Part 60, Appendix F (condition 10).
- A continuous monitoring system shall be installed and operated, on both turbines, to measure and record the flowrate of water used for injection for control of NO_X (condition 11).

- An annual report shall be submitted to the Division, by April 30, for the previous calendar year. This report shall contain, at a minimum, the following (condition 12):
 - o Total emissions of Oxides of Nitrogen
 - o Total emissions of Carbon Monoxide
 - Total quantity of water injected to control NO_X
 - o Exceedances, duration of such exceedances of various emission limits
 - o Consumption of natural gas by each of the turbines, boilers and duct burner
 - o Consumption of #2 Diesel Fuel by the starter engines
 - o Maximum power (MW) generated
 - o Total turbine-hours operated

With the issuance of the operating permit the source will be required to certify annually that they are in compliance with the conditions in the operating permit, which includes compliance with the emission limitations, fuel consumption limits and reporting requirements (including APEN reporting and excess emission reports). The majority of the information that the source is required to include in this annual report is already required to be reported under APEN (fuel consumption and annual emissions) and excess emission reporting requirements. Therefore, this requirement will not be included in the operating permit.

 APEN reporting (condition 13 and Colorado Regulation No. 3, Part A Section II.C)

The APEN reporting requirements will not be identified in the permit as a specific condition but is included in Section V (General Conditions) of the permit, condition 21.e.

Although not specifically identified in Colorado Construction Permit 91MR933, the turbines and duct burner are subject to the following applicable requirements:

- Particulate matter emissions from each turbine and the duct burner shall not exceed 0.5(FI)^{-0.26} lbs/mmBtu, where FI is the fuel input in mmBtu/hr (Reg 1, Section III.A.1.b)
- Sulfur dioxide emissions from each starter engine shall not exceed 0.8 lbs/mmBtu (Reg 1, Section VI.B.4.b.(i))
- Sulfur dioxide emissions from each turbine shall not exceed 0.35 lbs/mmBtu, on a 3-hour rolling average (Reg 1, Section VI.B.4.c.(ii) and VI.B.2)
- State-only Opacity of emissions from each turbine and the duct burner shall not exceed 20% (Reg 6, Part B, Section II.C.3)
- State-only Particulate matter emissions from the duct burner only shall not exceed 0.5(FI)^{-0.26} lbs/mmBtu, where FI is the fuel input in

- mmBtu/hr (Reg 6, Part B, Section II.C.1.b)
- State-only Sulfur dioxide emissions from each turbine shall not exceed 0.35 lbs/mmBtu (Reg 6, Part B, Section II.D.3.b)
- **Brush 3** (unit not equipped with a duct burner, simple cycle operation only only) is subject to the Acid Rain requirements as follows:
 - o Allocated SO₂ allowances are listed in 40 CFR Part 73.10(b), however, since this is a new unit, no allowances were allocated. SO₂ allowances must be obtained per 40 CFR Part 73 to cover SO₂ emissions for the particular calendar year.
 - o There are no NO_X emission limitations since this unit is not a coal-fired boiler.
 - o Acid rain permitting requirements per 40 CFR Part 72.
 - o Continuous emission monitoring requirements per 40 CFR Part 75.
 - o This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

Streamlining of Applicable Requirements

Opacity

The turbines and duct burner are subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. The turbines and the duct burner are also subject to the state-only Reg 6, Part B 20% opacity requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other at all times, all three opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency

It should be noted that since these turbines and duct burner burn natural gas as fuel, the Division will presume, in the absence of credible evidence to the contrary, that these units are in compliance with all of the opacity requirements.

PM

The duct burner is subject to the Reg 1 particulate matter requirements and the state-only, Reg 6, Part B particulate matter requirements. The particulate matter

requirements in both Reg 1 and Reg 6, Part B are the same standard. The Reg 1 particulate matter requirements apply at all times. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the quarterly excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B particulate matter requirements do not apply during periods of startup, shutdown and malfunction. As a result, the Reg 6, Part B requirements have been streamlined out of the permit.

SO_2

Only the Regulation No. 1 and Regulation No. 6, Part B sulfur dioxide standards are in the same units and can therefore be compared for the purposes of streamlining.

The Regulation No. 1 and No. 6, Part B SO₂ standards are the same, 0.35 lbs/mmBtu. The Regulation No. 6, Part B requirement is a state-only requirement and since Regulation No. 6, Part B incorporates the NSPS General Provisions (40 CFR Part 60 Subpart A), the SO₂ requirements do not apply during startup, shutdown and malfunction (as discussed in the PM streamlining section above). Therefore, the Regulation No. 1 SO₂ requirement is more stringent than the Regulation No. 6, Part B requirements will be streamlined out of the permit.

NO_X

Since the NSPS Subpart GG and BACT concentration limits are in the same units they can be compared for purposes of streamlining. The BACT concentration limits are applicable at all times. The Division considers that the NSPS Subpart GG requirements are not applicable during periods of startup, shutdown and malfunction (as discussed in the PM streamlining section above). Therefore, since the NSPS Subpart GG limits are less stringent than the BACT concentration limits, even with the alternate BACT limit for startup and shutdown,

the NSPS Subpart GG limits will be streamlined out of the operating permit.

Note that streamlined conditions are subsumed within the requirements identified in Section II of the permit. For purposes of compliance demonstration, compliance with the conditions in Section II of the permit also serve as compliance demonstration for the subsumed condition. Since the NSPS GG NO $_{\rm X}$ limit has been streamlined out in favor of the BACT NO $_{\rm X}$ limits, the source may wish to retain records of ambient temperature and humidity data which is used to convert NO $_{\rm X}$ values to ISO standard day conditions, in the event that the NO $_{\rm X}$ BACT limit is exceeded at such a level that compliance with the NSPS GG BACT limit is uncertain.

The duct burner is subject to an NSPS Subpart Db NO_X limit of 0.20 lbs/mmBtu, on a 30-day rolling average, which cannot be compared with the BACT NO_X concentration limit (in ppmvd @ 15% O_2 , on an hourly average), therefore, both requirements will be included in the permit.

Monitoring Requirements

These sources are subject to several types of monitoring requirements. The construction permit requires that both turbines and the duct burner be equipped with continuous emission monitors to monitor and record NO_X and CO emissions and the construction permit requires that these monitors be installed, maintained, calibrated and operated according to 40 CFR Part 60, Appendix F. Brush 3 (simple cycle unit) is subject to the Acid Rain requirements and as such is required to monitor emissions in accordance with the requirements in 40 CFR Part 75. Upon startup, Brush 3 was originally equipped with a Part 60 monitor and not a Part 75 monitor. A compliance order on consent (COC) was issued on December 10, 2001 because Brush 3 was out of compliance with the Part 75 monitoring requirements. The COC required Brush 3 to come into compliance with the Part 75 monitoring requirements. In March 2001, CPP submitted their Part 75 continuous emission monitoring certification package to EPA. Therefore, since the NO_X (and diluent monitor, either O₂ or CO₂) monitors must meet the requirements of 40 CFR Part 75, the Division will streamline out the 40 CFR Part 60 monitoring requirements for the Brush 3 NO_X (and diluent) monitor in favor of the Part 75 monitoring requirements. Note that the 40 CFR Part 60 excess emission reporting requirements for NO_X will remain in the permit as 40 CFR Part 75 does not contain any NO_X excess emission reporting requirements.

NSPS Subpart GG requires daily sampling of fuel to determine the nitrogen and sulfur content of the fuel. In an August 14, 1987 memo, the EPA waived the fuel sampling requirements to determine the nitrogen content for pipeline quality natural gas. The Acid Rain requirements allow sources that burn natural gas to use an alternate monitoring method in lieu of a continuous emission monitor for SO₂. These requirements are in 40 CFR Part 75, Appendix D. Specifically, this monitoring method requires the source to monitor fuel fed to the combustion

turbine for every hour that it combusts fuel. The source may then either sample and analyze natural gas for sulfur content or they may use the default SO₂ emission factor to determine SO₂. The default emission factor may be used if pipeline quality natural gas is burned. The Part 75 monitoring plan submitted by CPP on April 13, 2001 indicated that pipeline quality natural gas is used as fuel. In order to use the pipeline quality natural gas default emission factor, the source must demonstrate using any of the methods in 40 CFR Part 75, Appendix D, Section 2.3.1.4 that the fuel has a hydrogen sulfide content of less than 0.3 grain/100 scf. The source is using the default emission factor provided by Part 75 Appendix D for the purposes of determining SO₂ emissions. Therefore, the NSPS Subpart GG requirement to sample fuel daily for sulfur content will be streamlined out of the permit in favor of the Part 75 pipeline quality natural gas requirement. It should be noted that EPA determinations support the use of the "Optional Sulfur Dioxide Emissions Data Protocol for Gas-Fired and Oil-Fired Units" of Appendix D of 40 CFR Part 75 as a custom fuel monitoring schedule for SO₂ (March 13, 2000 letter from John Hepola to Daniel Ewan, re "Approval of Alternative Monitoring for NSPS Subpart GG Pine Bluff Energy, LLC - Pine Bluff Energy Center Pine Bluff, Arkansas Operating Air Permit # 1822-AOP-R0", Control Number 0000015, from EPA Region 6).

In addition, the construction permit requires that continuous monitoring systems shall be installed and operated to measure and record the flow rates of water used for injection for control of NO_X emissions. This requirement originated from the COC issued to Colorado Power Partners on December 18, 1995. Although not specifically identified in the construction permit, the source is also required by 40 CFR Part 60 Subpart GG to continuously monitor and record the fuel consumption rate and the ratio of water to fuel being fired in the turbine (40 CFR Part 60 § 60.334(a)). The Division generally considers the continuous emission monitoring systems to be more stringent than the water monitoring required by NSPS GG and the construction permit. Therefore, the Division will streamline out the NSPS GG monitoring of fuel and water to fuel ratio and the construction permit water monitoring requirements in favor of the continuous emission monitoring system, since the continuous emission monitoring system is more stringent. Note that there are several EPA determinations indicating that it is acceptable to use a continuous emission monitoring system in favor of the NSPS GG required monitoring.

Finally it should be noted that NSPS Db requires that records be kept for a period of 2 years. Reg 3, Part C, Section V.C.6 requires that records be retained for five (5) years. Therefore, the NSPS recordkeeping requirement will be streamlined out of the permit.

2. Emission Factors- Emissions from these simple and combined cycle turbines are produced during the combustion process, and are dependent upon operating conditions and specific properties of the natural gas being burned. The pollutants of concern are Nitrogen Oxides (NO_X) , Carbon Monoxide (CO),

Volatile Organic Compounds (VOC) and Particulate Matter (PM and PM₁₀). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted dependent upon the makeup of the fuel and combustion efficiency.

The emission factors that will be used to monitor compliance with the emission limits are as follows:

Pollutant	Turbines	Duct Burner	Starter Engine
PM	Brush 1 (turbine & duct burner) – 0.0055 lbs/mmBtu		42.5 lbs/10 ³ gal
	Brush 3 (turbine) - 0.0062 lbs/mmBtu)		
PM ₁₀	Brush 1 (turbine & duct burner) - 0.0055 lbs/mmBtu		42.5 lbs/10 ³ gal
	Brush 3 (turbine) - 0.0062 lbs/mmBtu)		
SO ₂	Brush 3 - CMS 0.6 lbs/mmSCF		39.7 lbs/10 ³ gal
	Brush 1 - 0.0034 lbs/mmBtu		
NO _X	CEM	CEM	554.6 lbs/10 ³ gal
CO	CEM	CEM	130 lbs/10 ³ gal
VOC	0.0021 lbs/mmBtu	5.5 lbs/mmSCF	18.4 lbs/10 ³ gal

Emission factors for the turbines (VOC and SO_2) are from AP-42 (4/00), Section 3.1, Table 3.1-2a. Emission factors for the duct burner are from AP-42 (3/98), Section 1.4, Table 1.4-2. Emission factors for the starter engines are from AP-42 (10/96), Section 3.3, Table 3.3-1, except VOC and NO_X emission factors are from the manufacturer (per memo from Tammy Essmeier to Division dated May 12, 1992). PM and PM_{10} emission factors for the units are from stack testing conducted December 21 and 22, 1999.

3. Monitoring Plan- CPP indicated in their application they would demonstrate compliance with the emission limits by multiplying the hours of operation of turbines by the lb per hour limits in the permit. This is not an acceptable compliance determination. The source shall be required to monitor compliance with the emission limits by monitoring fuel consumption and using emission factors based on fuel consumption or heat input. The source shall be required to record fuel consumption and calculate emissions monthly.

The continuous emission monitoring systems shall be used to monitor compliance with the BACT and annual NO_X and CO emission limitations. The NSPS Db NO_X limits for the duct burner (Brush 1) shall be monitored using the continuous emission monitor. Since NSPS Db does not require that a continuous emission monitor be used for combined cycle units, the Division considers that the specific provisions for continuous emission monitors specified in Subpart Db (i.e. minimum data requirements and restrictions on the use of Part 75 monitors, e.g. not including the bias or not using data replacement procedures for reporting purposes) do not apply. In addition, the continuous monitoring system required by 40 CFR Part 75 shall be used to monitor SO_2 emissions for Brush 3.

The heat content of the natural gas shall be determined monthly through either sampling and analysis or use of vendor analyses. In the absence of credible evidence to the contrary, compliance with the opacity, particulate matter and Reg

- 1 SO₂ limits shall be presumed provided natural gas is used as fuel. Provided the starter engines are operated for no more than 4 hrs at a time and the startup for the engines is completed within 1 hour, no EPA Method 9 opacity observations will be required to monitor compliance with the opacity requirements.
- **4. Compliance Status-** Current APENs reporting criteria and HAP emissions are on file with the Division. Brush 3 (simple cycle unit) is subject to the Acid Rain requirements. A COC was issued on December 10, 2001 because Brush 3 was out of compliance with the Acid Rain monitoring requirements (40 CFR Part 75). The COC requires the source to come into compliance with the Part 75 monitoring requirements. In March 2001, CPP submitted their Part 75 continuous emission monitoring certification package to EPA. Therefore, the Division considers that Brush 3 is in compliance with the Part 75 monitoring requirements.

<u>Units S003-S005</u> - Three (3) Cleaver-Brooks CB-700-600 Natural Gas Fired Boilers, Each Rated at 20 mmBtu/hr, SN's: L88129, L88130 and L88131. (Emergency Boilers for Heating Greenhouses)

Discussion:

- 1. Applicable Requirements- These boilers were installed and began operation in 1990. They were originally issued initial approval construction permit 91MR933-3 in 1992. In 1996, permits 91 MR933-1 thru –3 were combined into one permit (91MR933). Currently the boilers are covered under initial approval construction permit 91MR933 issued October 26, 1999 with the following conditions:
 - This source is subject to the odor requirements of Regulation No. 2 (condition 3)
 - Boilers are not generally a source of odor therefore this condition will not be specifically included in the permit but is included in the General Conditions (Section V) of the permit.
 - Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 5 and Colorado Regulation No. 1, Sections II.a.1 & 4).

As discussed under the turbines, this requirement will be modified in the permit to not specify that the 20% standard applies under "normal operations". In addition, the language in the permit will clarify that the 20% opacity requirement applies during shutdown and offline emissions

and the 30% opacity requirement will be written to include all the specific operational activities identified in Reg 1.

- This source shall be limited to a maximum consumption rate as listed below and all other activities, operation rates and numbers of equipment as stated in the application. Monthly records of the actual throughput shall be maintained by the permittee and made available to the Division for inspection upon request (condition 6).
 - o Consumption of natural gas for combustion in the three (3) boilers, together, shall not exceed 100 mmSCF/yr.
- Emissions of air pollutants for the three boilers together shall not exceed the following limitations (condition 8):

0	Particulate Matter	0.69 tons/yr
O	PM ₁₀	0.69 tons/yr
O	Nitrogen Oxides	7.00 tons/yr
O	Volatile Organic Compounds	0.30 tons/yr
0	Carbon Monoxide	1.80 tons/yr

Only the emission limit for NO_X will be included in the operating permit. The other emission limits are all below APEN de minimis levels and have a corresponding throughput limit to monitor compliance.

• The boilers are subject to Regulation No. 6, Part A, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (condition 9).

The construction permit only identified general recordkeeping, reporting and monitoring requirements. Specifically these units are subject to the following requirements:

- o Record and maintain records of the amounts of each fuel combusted during each day (40 CFR Part 60 § 60.48c(g))
- o Maintain records for two years (40 CFR Part 60 § 60.48c(i))
- APEN reporting (condition 13 and Colorado Regulation No. 3, Part A Section II.C).

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 21.e.

Although not specifically identified in Colorado Construction Permit 91MR933, the boilers are subject to the following applicable requirements:

• Particulate matter emissions **from each boiler** shall not exceed 0.5(FI)^{-0.26} lbs/mmBtu, where FI is the fuel input in mmBtu/hr (Reg 1, Section

- III.A.1.b)
- State-only Opacity of emissions from each boiler shall not exceed 20% (Reg 6, Part B, Section II.C.3)
- State-only Particulate matter emissions from each boiler shall not exceed 0.5(FI)^{-0.26} lbs/mmBtu, where FI is the fuel input in mmBtu/hr (Reg 6, Part B, Section II.C.1.b)

Streamlining of Applicable Requirements

Opacity

The boilers are subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operating conditions. The Reg 1 20% opacity requirement applies at all times, except for certain specific operational activities under which the Reg 1 30% opacity requirement applies. The boilers are also subject to the state-only Reg 6, Part B 20% opacity requirement. As indicated in the opacity streamlining section for the turbines and duct burner, neither opacity requirement can be streamlined out of the permit since no one opacity requirement is more stringent than the others at all times.

Since these boilers burn natural gas as fuel, the Division will presume, in the absence of credible evidence to the contrary, that these units are in compliance with all of the opacity requirements.

PM

The boilers are subject to the Reg 1 particulate matter requirements and the state-only, Reg 6, Part B particulate matter requirements. The particulate matter requirements in both Reg 1 and Reg 6, Part B are the same standard. The Reg 1 particulate matter requirements apply at all times. As indicated under the particulate matter streamlining section for the turbines and the duct burner the Reg 6, Part B particulate matter requirements are not applicable during startup, shutdown and malfunction. As a result, the Reg 6, Part B requirements have been streamlined out of the permit.

Monitoring

NSPS Dc requires that records be kept for a period of 2 years, while Reg 3, Part C, Section V.C.6 requires that records be retained for five (5). Therefore, the NSPS recordkeeping requirement will be streamlined out of the permit.

2. Emission Factors- Emissions from these boilers are produced during the combustion process, and are dependent upon operating conditions and specific properties of the natural gas being burned. The pollutants of concern are Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Volatile Organic Compounds (VOC), and Particulate Matter (PM and PM₁₀). Small quantities of Hazardous Air

Pollutants (HAPs) are also emitted dependent upon the makeup of the fuel and combustion efficiency.

The source shall be required to use the NO_X emission factor of 100 lbs/mmSCF from "EPA's Compilation of Air Pollution Emission Factors (AP-42)", Section 1.4, dated March 1998, Table 1.4-1, for Small Boilers.

Note that as stated previously, since the emission limits for PM, PM_{10} , CO and VOC are below APEN reporting levels those limitations will be not included in the operating permit and therefore, it is not necessary to determine an emission factor for those pollutants.

- **3. Monitoring Plan-** CPP indicated in their application they would demonstrate compliance with the emission limits by multiplying the hours of operation of the boilers by the lb per hour limits in the permit. This is not an acceptable compliance determination. The Division will require that the source monitor compliance with the NO_X limit by calculating emissions using the approved emission factor and the fuel consumption. In accordance with the requirement in NSPS Subpart Dc, the source will be required to record fuel consumption daily. Emission calculations shall be conducted monthly. Compliance with the particulate matter and opacity requirement will be presumed, in the absence of credible evidence to the contrary, whenever natural gas is used as fuel in these boilers.
- **4. Compliance Status-** Current APENs reporting criteria and HAP emissions are on file with the Division. Due to modification of the permit and review of the sources files these boilers are currently considered to be in compliance with all applicable requirements.

<u>Unit S006</u> - One (1) Ecodyne Cooling Tower, Two Cell Counter Flow, 25,000 gallons/min.

Discussion:

- 1. Applicable Requirements- The cooling tower was installed and began operation in 1990. The source filed an APEN with the Division in 1999. No construction permit will be issued for the cooling tower. The appropriate applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The applicable requirements for the cooling tower are as follows:
- Visible emissions shall not exceed twenty percent (20%) opacity.

Based on engineering judgement, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply.

Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling towers. In addition, there is really no "startup" involved in operating a cooling tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with this unit.

- Circulating water shall not exceed 6,000 mmgal per year (based on information submitted in CPP's February 4, 1999 submittal indicating 4000 hrs/yr of operation for the cooling tower at the design rate of 25,000 gal/min)
- Emissions of air pollutants shall not exceed the following limitations (as indicated in the APEN submitted February 4, 1999):

o Particulate Matter (PM) 2.5 tons/yr

o Particulate Matter < 10Fm (PM₁₀) 2.5 tons/yr

- APEN reporting in accordance with Regulation No. 3, Part A.II.C.
- 2. Emission Factors- Since cooling towers provide direct contact between the cooling water and the air passing through the tower, some liquid can be entrained in the air stream and emitted as "drift" droplets. Particulate matter contained in the "drift" is considered an emission as well as any chlorine or chloroform (VOC) from water treatment chemicals used in the cooling tower. A review of CPP's February 4, 1999 submittal indicates, that chlorinated compounds are not used in the cooling tower, therefore there are no chloroform or chlorine emissions. Approval of emission factors for this unit is necessary to verify compliance with the emission limits. The source proposed to calculate emissions from the cooling tower in the following manner:

 $PM = PM_{10} = (water flow, gpm) x (water density, lbs/gal) x (% drift) x (31.3% <math>PM/PM_{10}$ from drift) x (total solids concentration, ppm)

Where: % dr

% drift = 0.02% (based on AP-42, Section 13,4, dated 1/95, Table 13.4-1) 31.3% PM from drift - from EPA-600/7-79-251a, November 1979, "Effects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift - Volume 1, Technical Report", page 63

3. Monitoring Plan- The source shall be required to monitor the circulation rate of the water in the cooling tower and calculate emissions on a monthly basis. The water circulation rate is determined by the number of hours the tower has operated multiplied by the maximum capacity of the recirculating pump. Since the cooling tower only runs when the steam turbine runs, the hours of operation for the cooling tower will be based on the hours of operation metered on the steam turbine. In addition, particulate matter emissions are based on the total solids concentration in the cooling tower, therefore, the source will be required to

sample and analyze circulating water to determine the total solids concentration of the circulating water. In lieu of sampling the circulating water to determine the total solids concentration, the source will measure the specific conductivity of the circulating water and multiply that number by 0.67. In the absence of credible evidence to the contrary, compliance with the opacity requirement will be presumed provided the cooling tower and associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.

4. Compliance Status- Current APENs reporting criteria and HAP emissions are on file with the Division. Upon issuance of this operating permit this unit will be considered to be in compliance with all current applicable requirements.

IV. Insignificant Activities

- Two (2) small water treatment analysis labs
- Ten (10) water treatment chemical storage and dispensing tanks, 125 gallons each
- Sulfuric acid storage tank, 3800 gallons
- Ten (10) small propane gas tanks
- Ten (10) drums of lube oils, 55 gallons
- Tank of waste lube oil, 250 gallons
- Temporary storage for steam turbine lube oil, 3500 gallons
- Diesel storage tank, 300 gallons
- Unleaded storage tank, 300 gallons
- Gas unit and duct gas heaters, 5 @ 75 MBtu, 4 @ 100 MBtu, and 5 @ 150 MBtu.
- Portable gasoline powered air compressor
- Portable welding unit
- Portable power generator

V. Alternative Operating Scenarios

No alternative operating scenarios were requested for this facility.

VI. Permit Shield

The source requested the permit shield for those requirements it identified as applicable to the emission unit. There are two permit shields that can be obtained for the Operating Permit. In general, the permit shield applies to the applicable requirements and states that compliance with the Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the Operating Permit. If the source specifically requests and provides a justification, they can be shielded from requirements that are not applicable to the facility or to an emission unit. Because the source only identified applicable requirements and did not identify any non-applicable

requirements that they wished to be shielded from the Division did not include any specific non-applicable requirements in the permit shield.

The following applicable requirements were streamlined out of the permit and have been included in the permit shield.

Turbines and duct burner

- State-only particulate matter (0.5(FI)^{-0.26}) requirement for duct burner only (Reg 6, Part B, Section II.C.2), streamlined out since Reg 1 particulate matter requirement is more stringent.
- State-only 0.35 lbs/mmBtu SO₂ requirement for the turbines (Reg 6, Part B, Section II.D.3.b), streamlined out since Reg 1 SO₂ requirement is more stringent.
- 75 ppmvd NO_X at 15% O₂ requirement for the turbines (Colorado Construction Permit 91MR933 and 40 CFR Part 60 Subpart GG § 60.332(b), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since the NO_X BACT limit (30 or 38 ppmvd at 15% O₂) is more stringent. Note this also includes the exemptions from the standard in 40 CFR Part 60 Subpart GG §§ 60. 60.332(f) & (i).
- Continuous monitoring system requirement to monitor and record the fuel consumption rate and the ratio of water to fuel being fired in the turbine (40 CFR Part 60 Subpart GG § 60.334(a), streamlined out in favor of the more stringent continuous emission monitoring requirements.
- Continuous monitoring system requirement to monitor water flow rates (Colorado Construction Permit 91MR933), streamlined out in favor of the more stringent continuous emission monitoring requirements.
- Continuous emission monitoring system for Brush 3 NO_X and diluent monitors only shall meet the requirements in 40 CFR Part 60 (Colorado Construction Permit 91MR933, conditions 9.h & m and 10), streamlined out in favor of the more stringent continuous emission monitoring system requirements in 40 CFR Part 75.
- Monitor sulfur and nitrogen content of fuel (40 CFR Part 60 Subpart GG § 60.334(b)) and test methods and procedures for fuel sampling (40 CFR Part 60 Subpart GG §§ 60.335(d) & (e)), streamlined out in favor of the continuous emission monitor (nitrogen sampling) and the Acid Rain requirement for pipeline quality natural gas (sulfur sampling).
- Excess emission reporting for any one-hour period during which the average water-to fuel ratio is less that the ratio determined by the performance test and/or any period nitrogen content is greater than that used in the performance test (40 CFR Part 60 Subpart GG § 60.334(c)(1)), streamlined out in favor of reporting excess NO_X emissions determined by the continuous emission monitoring system.
- Excess emission reporting for any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 % (40 CFR Part 60 Subpart GG § 60.334(c)(2)), streamlined out in favor of the Acid

- Rain requirement for pipeline quality natural gas.
- 2 year record retention requirement (40 CFR Part 60 Subpart Db § 60.49b(o), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since the Reg 3, Part C, Section V.C.6 recordkeeping requirements (5 yr record retention) are more stringent.

Boilers

- State-only particulate matter (0.5(FI)^{-0.26}) requirement for duct burner only (Reg 6, Part B, Section II.C.2), streamlined out since Reg 1 particulate matter requirement is more stringent.
- 2 year record retention requirement (40 CFR Part 60 Subpart Dc § 60.48c(i), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since the Reg 3, Part C, Section V.C.6 recordkeeping requirements (5 yr record retention) are more stringent.

VII. Acid Rain Provisions:

Brush 1

In their comments on the draft permit submitted December 19, 2001, the source indicated that Brush 1 (combined cycle unit) was not subject to the requirements of the Acid Rain Program. The source cited two potential exemptions for this particular unit: the cogeneration facility exemption (72.6(b)(4)(i)) and the independent power production facility exemption (72.6(b)(6)).

A cogeneration unit is "a unit that has equipment used to produce electrical energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating or cooling purposes, through the sequential use of energy". The gas turbine can generate electricity directly (simple cycle mode) and the exhaust from the gas turbine, with the aid of a duct burner, is used to generate steam to drive a steam turbine for additional electricity generation and then the exhaust is used to heat water which is used to heat a greenhouse complex. Therefore, this unit meets the definition of a cogeneration unit as it uses energy sequentially. The cogeneration exemption in 72.6(b)(4)(i) specifies that cogeneration facilities constructed for the purpose of supplying equal to or less than the one-third its potential electrical output capacity or equal to or less than 219,000 Mwe-hrs actual electric output on an annual basis to any utility power distribution system for sale. The source indicated that in August 1988, the source entered into a 15 year power purchase agreement with a local utility and that the maximum annual capacity under the contract was 132,000 MW-hr (for the gas turbine). Since the maximum annual capacity specified in the contract is less than 219,000 MW-hr, it supports the "intent" requirement in the exemption. The source indicated that the Brush 1 gas turbine (25 MW) is subject to permit restrictions that limit operation and therefore limits the actual power output to less than 219,000. Based on the fuel consumption limits in the permit and assuming

a natural gas Btu content of 1000 Btu/scf, Brush 1 could operate as a simple cycle unit for 5,333 hrs/yr or 3,733 hrs/yr as a combined cycle unit. In simple cycle mode the unit serves a 25 MW generator and in combined cycle mode an additional 30 MW steam generator is available (55 MW total). Therefore, under the permit limitations, the unit could actually generate 133,325 MW-hr under simple cycle mode or 205,315 MW-hr under combined cycle mode. Therefore, the Division believes that the cogeneration exemption does apply to Brush 1.

In addition, the source provided information indicating that the independent power production facility exemption may also apply. The source indicated that they had entered into a 15 year power purchase agreement with Public Service Co in August 1988 and that the maximum annual capacity under the contract is 132,000 MW-hr (for the turbine). Although the source did not provide the power purchase agreement, the planned net output capacity at the time of this agreement, has been determined to be 55 MW, as indicated in the construction permit application for this facility dated November 1, 1988. Note that although the facility consisted of two (2) gas turbines, each with 25 MW capacity and the 30 MW steam turbine, one gas turbine was only intended to operate as a backup, therefore, only one gas turbine and the steam turbine are considered as the net planned output capacity. The 132,000 MW-hr capacity specified in the contract exceeds 15% of the total planned net output (55 MW x 8760 hrs = 481,800 MW-hr), so the requirements in 72.6(b)(6)(i) are met. In addition, although the total installed output capacity of the facility now exceeds 130% of the planned net output capacity (i.e. the construction permit was revised to allow the back-up turbine to operate simultaneously with the primary turbine), the additional installed output capacity (Brush 3) and that unit is subject to the Acid Rain program requirements, as discussed below. Therefore, the requirement in 72.6(b)(6)(ii) is also met and Brush 1 may also be considered exempt from the Acid Rain requirements under the provisions of 72.6(b)(6).

Brush 3

Brush 3 (simple cycle unit) is an affected unit under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78 and as such the source is required to have provisions for the Acid Rain requirements in its Title V permit. Units subject to the Acid Rain requirements are required to hold adequate SO_2 allowances and have NO_X limitations. This facility is not listed under 40 CFR 73.10(b)(2) and therefore must obtain SO_2 allowances as needed. Since these units are not coal-fired boilers, they do not have any NO_X limitations.

Typically, units subject to the Acid Rain requirements are required to continuously measure and record emissions of SO_2 , NO_X (with diluent monitor either CO_2 or O_2) and CO_2 as well as opacity and volumetric flow in accordance with the requirements in 40 CFR Part 75. Since this unit burns natural gas, the unit is not required to have a continuous opacity monitor and can use an alternate monitoring method (Appendix D), in lieu of installing and operating a

continuous emission monitor for SO ₂ .		
In March 2001, CPP submitted their Part 75 continuous emission monitoring certification package to EPA.		